BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2013-3-E

In the Matter of	)	
Annual Review of Base Rates	)	**REBUTTAL TESTIMONY**
for Fuel Costs for	)	**OF KIM H. SMITH FOR**
Duke Energy Carolinas, LLC	)	**DUKE ENERGY CAROLINAS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kim H. Smith. My business address is 526 South Church Street, Charlotte, North Carolina.

Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted direct testimony in this proceeding on August 2, 2013.

Q. HAVE YOU REVIEWED THE TESTIMONY SUBMITTED BY KEVIN O'DONNNELL ON BEHALF OF SOUTH CAROLINA ENERGY USERS COMMITTEE ("SCEUC")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address some assertions and inaccuracies in SCEUC witness O'Donnell's testimony.

Q. WHAT ARE SOME OF THE STATEMENTS THAT IN WITNESS O'DONNELL'S TESTIMONY THAT ARE INACCURATE?

A. Witness O'Donnell states on page 2, line 23 of his testimony that "on August 2, 2003 [sic], Duke asked to increase its fuel rate from 0.5882 cents per kWh to 0.6576 cents per kWh." This statement is inaccurate. On August 2, 2013, Duke Energy Carolinas, LLC ("DEC" or the "Company") filed its fuel cost recovery filing before this Commission in which it requested an increase in the base fuel factor from 1.8846 cents per kWh to 2.2049 cents per kWh. (*See* Smith Direct Testimony, p. 5, lines 19 -22). As a result, the cents per kWh costs that witness O'Donnell cites as DEC's current and proposed overall fuel rates do not accurately reflect the fuel factors that the Company filed in its application.

Q. WITNESS O'DONNELL ASSERTS THAT DEC OFFICIALS TOLD INDUSTRIAL CUSTOMERS IN JULY 2013 THAT THERE WOULD BE LITTLE CHANGE IN FUEL RATES IN 2013. DO YOU AGREE WITH THAT ASSERTION?

A. No, I do not. I am not aware of any conversation that DEC officials had with industrial customers whereby DEC officials informed them that there would be little change in their fuel rates. I am aware, however, that in late July 2013, DEC officials communicated with a representative for SCEUC whereby DEC officials informed SCEUC through its representative that (a) DEC's initial proposed fuel rate that it had not yet filed was much higher than the forecasted amount communicated to both SCEUC and ORS in a letter from me dated May 31, 2013, and that (b) DEC planned to pare down that increase when it actually filed its application to 7.1% for industrials, as compared to a projected high end of the range of 5.8% as communicated in the May 31, 2013 letter. The Company subsequently made its fuel cost recovery application to this Commission on August 2, 2013, which, if approved, would have resulted in a fuel rate increase of 6.8% for its industrial customers in South Carolina.

Subsequent to DEC's August 2nd filing, DEC, in consultation with the South Carolina Office of Regulatory Staff ("ORS"), refreshed its assumptions related to certain commodity costs. The volatility of commodity prices allowed us to decrease the fuel factor. As referenced in the filing of the Settlement Agreement today between DEC and ORS, DEC is now asking for a 5.64% fuel rate increase for industrial customers. This percentage falls within the range of a .1% - 5.8% increase that was forecasted and provided to SCEUC in DEC's aforementioned May 31, 2013 letter.

Q. DO YOU BELIEVE, AS WITNESS O'DONNELL ASSERTS, THAT DEC "MISSED" ITS FUEL FORECAST?

A. No, I do not. The Company is sensitive to fuel cost increases to its customers and tries to ensure that its communications to its customers depict as accurately as is reasonably possible the potential impacts of fuel rate increases or decreases. As a result, the Company specifically referenced its under-collection/over-collection of fuel costs in the forecast that it communicated to the ORS and SCEUC on May 31, 2013. Specifically, DEC stated:

> The 2nd Quarter 2013 forecast results are higher than the current fuel factors, **due to the completion of the give back of an over recovery in the current rates.** Based on projections of fuel costs for the various sources of energy, environmental costs, forecasts of usage by South Carolina customers, **and taking into account prior period over/under recovery,** and including estimated merger savings, Duke Energy Carolinas expects to request a fuel factor between 1.9 and 2.2 cents/kWh for all classes of customers in its next fuel proceeding….Beginning October 1, 2013, the projected increase to a range between 1.9 and 2.2 cents/kWh for all classes of customers would result in an increase in the average South Carolina industrial customer's power bill of **.1 to 5.8 percent.**

(emphasis added). Thus, it is apparent to me from that communication that DEC was very aware of its forecast, the under-collection/over-collection issue, and the fact that its fuel cost increase could affect industrial customers anywhere from .1% to 5.8%.

Q. WITNESS O'DONNELL ASSERTS THAT A MONTHLY ANALYSIS, IF NOT MORE FREQUENT, OF DEC'S FUEL COSTS WOULD HAVE

EXPOSED THE VARIATION IN FUEL COSTS LEADING TO THIS "UNUSUALLY HIGH FUEL RATE INCREASE." DO YOU AGREE WITH THAT STATEMENT?

A. No. The Company does in fact have a monthly analysis of what was occurring with its over/under-collection balance. Schedule 4 of DEC's May 2013 Monthly Fuel Report, which it filed publicly with the Commission (and which is attached here as Smith Rebuttal Exhibit A), clearly demonstrates that the over-collection balance steadily declined as would be expected, because the current fuel rates were intended to return to customers approximately $66 million of previously over-collected funds and create no new over- or under-collection.

Q. DOES THIS CONLUDE YOUR TESTIMONY?

A. Yes, it does.

Smith Rebuttal Exhibit A

Exhibit A
Schedule 1

DUKE ENERGY CAROLINAS
SUMMARY OF MONTHLY FUEL REPORT
SC Code Ann. §58-27-865 (Supp. 2012)

Line No.	Fuel Expenses:	May 2013
1	Fuel and fuel-related costs	$ 134,527,631
2	Less fuel expenses (in line 1) recovered through intersystem sales (a)	14,142,431
3	Total fuel and fuel-related costs (line 1 minus line 2)	$ 120,385,200
	MWH sales:	
4	Total system sales.	6,478,307
5	Less intersystem sales	381,938
6	Total sales less intersystem sales	6,096,369
7	Total fuel and fuel-related costs (¢/KWH) (line 3/line 6)	1.9747
8	Current fuel and fuel-related cost component (¢/KWH) (per Schedule 4, Line 4 + Line 10)	1.8899
	Generation Mix (MWH):	
	Fossil (by primary fuel type):	
9	Coal	1,964,042
10	Biomass	-
11	Fuel Oil	48
12	Natural Gas - Combustion Turbine	31,844
13	Natural Gas - Combined Cycle	538,509
14	Total fossil	2,534,443
15	Nuclear 100%	5,351,943
16	Hydro - Conventional	305,103
17	Hydro - Pumped storage	(82,262)
18	Total hydro	222,841
19	Solar Distributed Generation	1,468
20	Total MWH generation	8,110,695
21	Less joint owners' portion	1,361,243
22	Adjusted total MWH generation	6,749,452
	(a) Line 2 includes:	
	Fuel from intersystem sales (Schedule 3)	$ 14,120,399
	Fuel in loss compensation	22,032
	Total fuel recovered from intersystem sales	$ 14,142,431

Note: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY CAROLINAS
DETAILS OF FUEL AND FUEL-RELATED COSTS
SC Code Ann. §58-27-865 (Supp. 2012)

Fuel and fuel-related costs:	May 2013
Steam Generation - FERC Account 501	
0501016 coal blending merger savings	$ 1,493,125
0501016 coal procurement merger savings	(117,769)
0501016 transportation merger savings	345,346
0501110 coal consumed - steam	73,153,794
0501222-0501223 biomass/test fuel consumed @ avoided fuel cost	-
0501310 fuel oil consumed - steam	139,025
0501330 fuel oil light-off - steam	660,581
Total Steam Generation - Account 501	75,674,102
Environmental Costs	
0509000, 0557451 emission allowance expense	9,482
0502020, 030, 040 reagents expense	2,194,055
0502160 reagent procurement merger savings	5,741
Emission allowance gains	(28,750)
Total Environmental Costs	2,180,528
Nuclear Generation - FERC Account 518	
0518100 burnup of owned fuel	28,452,062
0518600 nuclear fuel disposal cost	5,033,686
Total Nuclear Generation - 100%	33,485,748
Less joint owners' portion	8,348,014
Total Nuclear Generation - Account 518	25,137,734
Other Generation - FERC Account 547	
0547100 natural gas consumed - Combustion Turbine	1,801,619
0547101 natural gas consumed - Combined Cycle	18,620,698
0547123 gas capacity merger savings	69,022
0547200 fuel oil consumed - Combustion Turbine	11,499
Total Other Generation - Account 547	20,502,838
Solar Distributed Generation @ Avoided Fuel Cost	61,080
Total fossil and nuclear fuel expenses included in base fuel component	123,556,282
Fuel component of purchased and interchange power per Schedule 3	9,439,785
Fuel related component of purchased power (economic accrual)	1,531,564
Total fuel and fuel-related costs	$ 134,527,631

Note: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY CAROLINAS
DETAILS OF FUEL AND FUEL-RELATED COSTS
SC Code Ann. §58-27-865 (Supp. 2012)

Other fuel expenses not included in fuel and fuel-related costs:		May 2013
Net proceeds from sale of by-products	$	132,367
0501223 biomass non-fuel avoided cost		-
0501223 biomass excess above avoided cost		-
0501224 North Carolina incremental renewable fuel		-
0502080, 0502090, 0502150 sorbents		102,879
0509213 RECs consumption expense		-
0518610 spent fuel canisters-accrual		-
0518620 canister design expense		81,346
0518700 fuel cycle study costs		-
0547127 gas desk merger savings		12,217
Non-fuel component of purchased and interchanged power		3,471,464
Total other fuel expenses not included in fuel and fuel-related costs:		3,800,273
Less Solar Distributed Generation @ Avoided Fuel Cost		(61,080)
Adjusted total other fuel expenses not included in fuel and fuel-related costs:	$	3,739,193
Total FERC Account 501 - Total Steam Generation		75,674,102
Total FERC Account 518 - Total Nuclear Generation		25,219,080
Total FERC Account 547 - Other Generation		20,502,838
Total RECs Consumption Expense		-
Total Reagents Expense		2,302,675
Total Gain/Loss from Sale of By-Products		132,367
Total Emission Allowance Expense		9,482
Total Gain/Loss from Sale of Emission Allowances		(28,750)
Total Purchased and Interchanged Power Expenses		14,442,813
Total Merger Savings Excluded from Fuel Recovery		12,217
Total Fuel, Fuel-Related and Purchased Power Expenses	$	138,266,824

Note: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY CAROLINAS
PURCHASED POWER AND INTERCHANGE
SOUTH CAROLINA

May 2013

Purchased Power	Total	Capacity		Non-capacity		
Marketers, Utilities, Other	$	MW	$	MWH	Fuel $	Non-Fuel $
Alcoa Power Generating Inc.	$ 266,465	-	-	9,265	$ 162,544	$ 103,921
Blue Ridge Electric Membership Corp.	1,268,969	46	$ 645,178	26,191	380,512	243,279
City of Concord	6,063	-	609	120	(7,659)	13,113
City of Kings Mtn	8,979	3	8,979	-	-	-
Haywood Electric	370,050	17	178,603	6,415	116,783	74,664
Lockhart Power Co.	19,272	7	19,272	-	-	-
MISO	3	-	-	-	2	1
NCMPA	2,106,929	-	-	66,973	1,289,215	817,714
Oglethorpe Power	8,250	-	-	550	5,032	3,218
Piedmont Electric Membership Corp.	640,479	21	319,417	13,019	195,848	125,214
PJM Interconnection LLC	408,254	-	-	11,723	249,035	159,219
Rutherford Electric Membership Corp.	83,027	-	-	2,220	67,388	15,639
Southern	(3,080)	-	-	(140)	(1,879)	(1,201)
The Energy Authority	16,540	-	-	585	10,089	6,451
Town of Dallas	584	-	584	-	-	-
Town of Forest City	19,272	7	19,272	-	-	-
TVA	236,290	-	-	9,420	144,137	92,153
DE Progress - Native Load Transfer	3,244,111	-	-	97,651	2,442,017	802,094
DE Progress - Native Load Transfer Savings	207,033	-	-	-	207,033	-
DE Progress - Fees	6,176	-	-	-	-	6,176
Generation Imbalance	214,716	-	-	6,366	128,880	85,836
Energy Imbalance - Purchases	157,572	-	-	2,686	96,119	61,453
Energy Imbalance - Sales	(63,757)	-	-	-	(53,821)	(9,936)
	$ 9,222,197	101	$ 1,191,914	253,044	$ 5,431,275	$ 2,599,008

Purchased Power	Total	Capacity		Non-capacity		
Cogen, Purpa, Small Power Producers	$	MW	$	MWH	Fuel $	Non-Fuel $
Active Concepts, LLC	$ 537	-	-	11	$ 449	$ 88
Arndt Farm, LLC	54,765	-	-	886	36,841	17,924
Belwood Farm, LLC	44,030	-	-	718	29,877	14,153
Coc Surry, LFG, LCC	157	-	-	3	112	45
Cherokee County Cogeneration Partners	1,949,762	-	$ 174,652	31,600	1,390,260	384,850
City of Charlotte	2,389	-	-	34	1,428	961
Concord Energy, LLC	332,744	-	-	4,781	198,881	133,863
Davidson Gas Producers, LLC	73,665	-	-	1,058	44,029	29,636
Dibrell Farm, LLC	41,610	-	-	697	28,979	12,631
Dixon Dairy Road, LLC	42,016	-	-	686	28,554	13,462
Durham Landfill Electricity, LLC	94,482	-	-	1,629	67,766	26,716
Gas Recovery Systems, LLC	144,495	-	-	2,131	88,658	55,837
Gaston County	124,350	-	-	1,990	82,767	41,583
Greenville Gas Producer, LLC	84,476	-	-	1,732	72,035	12,441
Lockhart - Lower Pacolet Hydro	32,429	-	-	465	19,355	13,074
Lockhart - Upper Pacolet Hydro	43,786	-	-	628	26,133	17,653
Lockhart - Minimum Flow	40,704	-	-	584	24,294	16,410
Lockhart Power Company	74,837	-	-	1,074	44,666	30,171
Lynwood Solar, LLC	917	-	-	20	835	82
Martin Truex, Jr. LLC	451	-	-	9	381	70
Mocksville Farm, LLC	55,150	-	-	893	37,140	18,010
Nypro, Inc.	1,664	-	-	33	1,389	275
Ronnie B. Powers	4,693	-	-	94	3,925	768
Spartanburg Water System	9,637	-	-	212	8,836	801
Sun Edison, LLC	202,407	-	-	2,985	124,191	78,216
Tencarva Machinery Company	1,343	-	-	27	1,108	235
Two Lines Farm, LLC	62,367	-	-	1,048	43,580	18,787
WM Renewable Energy, LLC	100,014	-	-	1,525	63,423	36,591
Other Cogens, Purpa and Small Power Producers	1,475,591			29,606	1,452,905	22,686
	$ 5,095,469	-	$ 174,652	87,159	$ 3,922,797	$ 998,020
TOTAL PURCHASED POWER	$ 14,317,666	101	$ 1,366,566	340,203	$ 9,354,072	$ 3,597,028
INTERCHANGES IN						
Other Catawba Joint Owners	7,522,175	-	-	690,732	4,376,568	3,145,607
Total Interchanges In	7,522,175	-	-	690,732	4,376,568	3,145,607
INTERCHANGES OUT						
Other Catawba Joint Owners	(7,397,028)	(866)	(134,209)	(677,111)	(4,290,855)	(2,971,964)
Catawba- Net Negative Generation	-	-	-	-	-	-
Total Interchanges Out	(7,397,028)	(866)	(134,209)	(677,111)	(4,290,855)	(2,971,964)
Net Purchases and Interchange Power	$ 14,442,813	(765)	$ 1,232,357	353,824	$ 9,439,785	$ 3,770,671

NOTE: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY CAROLINAS
INTERSYSTEM SALES*
SOUTH CAROLINA

MAY 2013

Schedule 3, SC, Sales, Month
Exhibit A, Page 2 of 2

	Total	Capacity		Non-capacity		
SALES	$	MW	$	MWH	Fuel $	Non-fuel $
Utilities:						
SC Public Service Authority - Emergency	$ 16,361	-	-	361	$ 11,146	$ 5,215
Market Based:						
Exelon Generation Company, LLC	-	-	-	-	(4)	4
NCMPA	125,695	-	$ 120,833	91	25,717	(20,855)
PJM Interconnection LLC	1,598,886	-	-	25,323	1,171,360	427,526
SC Electric & Gas Market based	63,450	-	-	900	38,055	25,395
The Energy Authority	(40)	-	-	30	807	(847)
TVA	-	-	-	-	9,752	(9,752)
Other:						
Cargill-Alliant, LLC - Mitigation sales	-	-	(1,310,000)	-	-	1,310,000
DE Progress - Native Load Transfer Savings	713,701	-	-	-	713,701	-
DE Progress - Native Load Transfer	12,359,316	-	-	337,516	11,671,628	687,688
DE Progress - Off System Sales/PJM Share	12,836	-	-	-	-	12,836
DE Progress - Purchases	457,557	-	-	17,161	457,557	-
Generation Imbalance	22,092	-	-	556	20,680	1,412
BPM Transmission	(190,135)	-	-			(190,135)
Total Intersystem Sales	**$ 15,179,719**	**-**	**$(1,189,167)**	**381,938**	**$ 14,120,399**	**$ 2,248,487**

* Sales for resale other than native load priority.

NOTE: Detail amounts may not add to totals shown due to rounding.

Exhibit A
Schedule 4

Duke Energy Carolinas
Over / (Under) Recovery of Fuel Costs
May 2013
SC Code Ann. §58-27-865

Line No.			Residential	Commercial	Industrial	Total
1	S.C. Retail kWh sales	Input	391,252,901	448,536,564	723,764,451	1,563,553,916
	Base fuel component of recovery					
2	Billed base fuel rate (¢/kWh)	Input	1.9489	1.9489	1.9489	1.9489
3	Merger fuel savings decrement (¢/kWh)	Input	(0.0643)	(0.0643)	(0.0643)	(0.0643)
4	Net billed base fuel rate (¢/kWh)	L2 + L3	1.8846	1.8846	1.8846	1.8846
5	Billed base fuel expense	L1 * L4 /100	$7,373,552	$8,453,120	$13,640,065	$29,466,737
6	Incurred base fuel rate (¢/kWh)	Input	1.9187	1.9187	1.9187	1.9187
7	Incurred base fuel expense	L1 * L6 / 100	$7,507,131	$8,606,256	$13,887,167	$30,000,554
8	Difference in ¢/kWh (Billed - Incurred)	L4 - L6	(0.0341)	(0.0341)	(0.0341)	(0.0341)
9	Base fuel over/(under) recovery	L1 * L8 / 100	**($133,579)**	**($153,136)**	**($247,102)**	**($533,817)**
	Environmental component of recovery					
10	Billed rates by class (¢/kWh)	Input	(0.0008)	0.0036	0.0097	0.0053
11	Billed environmental expense	L1 * L10 / 100	($3,130)	$16,147	$70,205	**$83,222**
12	Incurred rate by class (¢/kWh)	Input	0.0547	0.0301	0.0184	0.0308
13	Incurred environmental expense	L1 * L12 / 100	$214,120	$135,010	$133,063	**$482,193**
14	Difference in ¢/kWh (billed - incurred)	L10 - L12	(0.0555)	(0.0265)	(0.0087)	(0.0255)
15	Environmental over/(under) recovery	L11 - L13	**($217,250)**	**($118,863)**	**($62,858)**	**($398,971)**
	Economic purchase component of recovery					
16	S.C. kWh sales % by class	L1 / L1T	25.02%	28.69%	46.29%	100.00%
17	Economic purchase accrual	L16 * L17T	**($98,293)**	**($112,683)**	**($181,828)**	**$ (392,804)**
18	Over / (under) recovery	L9 + L15 + L17	**($449,122)**	**($384,682)**	**($491,788)**	**($1,325,592)**
19	Prior period adjustment	Input				
20	Total over / (under) recovery	L18 + L19	**($449,122)**	**($384,682)**	**($491,788)**	**($1,325,592)**

Year 2012-2013

	Cumulative over / (under) recovery	Cumulative	Residential	Commercial	Industrial	Total Company
_/1	Balance ending May 2012	$48,990,906				
	June	53,476,590	$1,343,048	$1,285,908	$1,856,728	$4,485,684
	July	50,799,022	(823,121)	(726,165)	(1,128,282)	(2,677,568)
	August	56,949,138	2,136,571	1,735,521	2,278,024	6,150,116
	September	67,674,470	3,255,839	3,109,956	4,359,537	10,725,332
_/2	October	63,234,631	(1,148,653)	(1,291,044)	(2,000,142)	(4,439,839)
	November	50,191,517	(3,550,661)	(3,641,800)	(5,850,653)	(13,043,114)
	December	45,553,373	(1,546,121)	(1,246,280)	(1,845,743)	(4,638,144)
	January	41,535,765	(1,539,143)	(1,092,631)	(1,385,834)	(4,017,608)
	February	39,694,364	(726,845)	(492,790)	(621,766)	(1,841,401)
	March	33,290,359	(2,235,940)	(1,671,505)	(2,496,560)	(6,404,005)
	April	33,494,129	(30,454)	43,706	190,518	203,770
	May	$32,168,537	($449,122)	($384,682)	($491,788)	($1,325,592)

Notes:

Detail amounts may not recalculate due to percentages presented as rounded.

_/1 May 2012 ending balance reflects adjustments pursuant to Docket No. 2012-3-E - Order No. 2012-779.

_/2 Includes a prior period adjustment to offset June and July corrections which have been reflected in the May 2012 ending balance (see footnote _/1).

Smith Rebuttal Exhibit A

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED COST REPORT
May 2013

Description	Allen Steam	Belews Creek Steam	(H) Buck Gas/CC	Catawba Nuclear	Cliffside Steam	(H) Dan River Gas/CC
Cost of Fuel Received						
Coal (A)	$1,035,193	$37,435,635			$26,831,339	-
Biomass	-	-			-	
Fuel Oil (C)	129,738	286,417			550,336	-
Gas - CT						
Gas - CC			$10,680,130			$7,940,568
Total	$1,164,931	$37,722,052	$10,680,130		$27,381,675	$7,940,568
Received (¢/MBTU) Avg						
Coal (A)	404.84	393.12			427.40	
Biomass	-	-			-	
Fuel Oil	2,106.48	2,158.06			2,207.97	
Gas - CT						
Gas - CC			481.95			481.26
Weighted Average	444.86	395.58	481.95		434.44	481.26
Cost of Fuel Burned($) (D)						
Coal (E)	$1,537,946	$37,876,549			$17,215,330	-
Biomass (F)	-	-			-	
Fuel Oil (G)	42,089	272,142			622,827	-
Gas - CT						
Gas - CC			$10,680,130			$7,940,568
Nuclear				$10,337,586		
Total	$1,580,035	$38,148,691	$10,680,130	$10,337,586	$17,838,157	$7,940,568
Burned (¢/MBTU) Avg						
Coal	461.67	385.45			426.93	
Biomass	-	-			-	
Fuel Oil	2,023.50	2,248.92			2,228.68	
Gas - CT						
Gas - CC			481.95			481.26
Nuclear				61.02		
Weighted Average	471.36	387.74	481.95	61.02	439.33	481.26
Generated (¢/kWh) Avg						
Coal	6.28	3.54			3.91	-
Biomass	-	-			-	-
Fuel Oil	-	-			-	-
Gas - CT						
Gas - CC			3.49			3.42
Nuclear				0.61		
Weighted Average	6.46	3.56	3.49	0.61	4.05	3.42
Burned MBTU's						
Coal	333,128	9,826,527			4,032,341	
Biomass	-	-			-	
Fuel Oil	2,080	12,101			27,946	
Gas - CT						
Gas - CC			2,216,017			1,649,940
Nuclear				16,942,020		
Total	335,208	9,838,628	2,216,017	16,942,020	4,060,287	1,649,940
Net Generation (mWh)						
Coal	24,476	1,070,193			440,744	
Biomass	-	-			-	
Fuel Oil	-	-			-	-
Gas - CT						
Gas - CC			306,042			232,467
Nuclear 100%				1,685,666		
Hydro (Total System)						
Solar (Total System)						
Total	24,476	1,070,193	306,042	1,685,666	440,744	232,467
Cost of Reagents Consumed ($)						
Ammonia	-	$348,102	$16,230		$109,796	$30,052
Limestone (E)	$44,250	696,227	-		526,861	
Urea	31,808	-	-		-	
Organic Acid	-	-	-		-	
Sorbents	35,125	-	-		-	
Total	$111,183	$1,044,329	$16,230		$636,657	$30,052

Description	Lee Steam/CT	Lincoln CT	Marshall Steam	McGuire Nuclear	Mill Creek CT
Cost of Fuel Received					
Coal (A)	-		$32,900,510		
Biomass	-		-		
Fuel Oil (C)	$207,633	-	650,831		-
Gas - CT	233,673	$445,172			$340,203
Gas - CC					
Total	$441,307	$445,172	$33,551,341		$340,203
Received (¢/MBTU) Avg					
Coal (A)			424.74		
Biomass	-	-	-		-
Fuel Oil	2,019.19	-	-		-
Gas - CT	489.59	460.16			456.02
Gas - CC					
Weighted Average	760.73	460.16	433.14		456.02
Cost of Fuel Burned($) (D)					
Coal (E)	-		$16,523,969		
Biomass (F)	-		-		
Fuel Oil (G)	$3,284	$4,846	366,974		-
Gas - CT	233,673	445,172			$340,203
Gas - CC					
Nuclear				$11,098,697	
Total	$236,958	$450,017	$16,890,943	$11,098,697	$340,203
Burned (¢/MBTU) Avg					
Coal	-		402.28		
Biomass	-		-		
Fuel Oil	2,078.58	1,079.19	2,287.72		-
Gas - CT	489.59	460.16			456.02
Gas - CC					
Nuclear				64.28	
Weighted Average	494.84	463.02	409.61	64.28	456.02
Generated (¢/kWh) Avg					
Coal	(B)		3.85		
Biomass	-		-		
Fuel Oil	20.53	15.14	-		-
Gas - CT	4.97	6.38			5.88
Gas - CC					
Nuclear				0.64	
Weighted Average	5.87	6.42	3.93	0.64	5.88
Burned MBTU's					
Coal	-		4,107,629		
Biomass	-		-		
Fuel Oil	158	449	16,041		-
Gas - CT	47,728	96,743			74,602
Gas - CC					
Nuclear				17,265,207	
Total	47,886	97,192	4,123,670	17,265,207	74,602
Net Generation (mWh)					
Coal	(680)		429,309		
Biomass	-		-		
Fuel Oil	16	32	-		-
Gas - CT	4,701	6,982			5,781
Gas - CC					
Nuclear 100%				1,727,502	
Hydro (Total System)					
Solar (Total System)					
Total	4,037	7,014	429,309	1,727,502	5,781
Cost of Reagents Consumed ($)					
Ammonia			-		
Limestone (E)			$284,643		
Urea			106,085		
Organic Acid			-		
Sorbents			67,754		
Total			$458,482		

Description	Oconee Nuclear	(H) Riverbend Steam/CT	Rockingham CT	Current Month	Total 12 ME May 2013
Cost of Fuel Received					
Coal (A)		-		$98,202,677	$1,106,687,187
Biomass		-		-	4,306
Fuel Oil (C)		($643,494)	-	1,181,462	48,715,320
Gas - CT		-	$782,571	1,801,619	22,926,018
Gas - CC				18,620,698	183,183,519
Total		(643,493.75)	$782,571	$119,806,456	$1,361,516,349
Received (¢/MBTU) Avg					
Coal (A)				412.58	406.04
Biomass		-	-	-	614.32
Fuel Oil		-	-	2,162.31	2,245.99
Gas - CT		-	468.78	478.51	328.43
Gas - CC				481.95	400.60
Weighted Average		-	468.78	426.22	415.82
Cost of Fuel Burned($) (D)					
Coal (E)		-		$73,153,794	$1,143,370,564
Biomass (F)		-		-	97,015
Fuel Oil (G)		($504,426)	-	811,105	46,754,516
Gas - CT		-	$782,571	1,801,619	22,926,018
Gas - CC				18,620,698	183,183,519
Nuclear	$12,049,465			33,485,748	339,007,579
Total	$12,049,465	($504,426)	$782,571	$127,872,964	$1,735,339,211
Burned (¢/MBTU) Avg					
Coal		-		399.76	404.71
Biomass		-		-	546.78
Fuel Oil		-	-	1,380.02	2,214.90
Gas - CT		-	468.78	478.51	328.43
Gas - CC				481.95	400.60
Nuclear	61.68			62.31	58.24
Weighted Average	61.68	-	468.78	167.47	188.74
Generated (¢/kWh) Avg					
Coal		-		3.72	3.81
Biomass		-		-	6.89
Fuel Oil		-	-	1,689.80	INF.
Gas - CT		-	5.44	5.66	3.82
Gas - CC				3.46	2.89
Nuclear	0.62			0.63	0.59
Weighted Average	0.62	-	5.44	1.58	1.81
Burned MBTU's					
Coal		-		18,299,625	282,514,275
Biomass		-		-	17,743
Fuel Oil		-	-	58,775	2,110,912
Gas - CT		-	166,937	386,010	6,980,438
Gas - CC				3,865,957	45,726,764
Nuclear	19,536,603			53,743,830	582,095,157
Total	19,536,603	-	166,937	76,354,197	919,445,288
Net Generation (mWh)					
Coal		-		1,964,042	29,971,219
Biomass		-		-	1,408
Fuel Oil		-	-	48	874
Gas - CT		-	14,380	31,844	599,417
Gas - CC				538,509	6,335,461
Nuclear 100%	1,938,775			5,351,943	57,633,673
Hydro (Total System)				222,841	1,195,497
Solar (Total System)				1,468	12,295
Total	1,938,775	-	14,380	8,110,695	95,749,844
Cost of Reagents Consumed ($)					
Ammonia		-		$504,181	$8,553,945
Limestone (E)		-		1,551,980	17,544,941
Urea		-		137,893	3,652,478
Organic Acid		-		-	-
Sorbents		-		102,879	624,372
Total		-		$2,296,934	$30,375,736

(A) Coal receipts exclude -57,469 tons and -$2,794,435 associated with terminals for the current month.
(A) Cost of coal received includes a transfer of inventory from Dan River to Belews Creek valued at $8,766,455 for the twelve months ended. The cost of the transfer between stations net to zero with the exception of $1,131,000 in freight costs.
(B) Cents/kWh not computed when costs and/or net generation is negative.
(C) Cost of fuel oil received includes a transfer of inventory from Dan River to Belews Creek valued at $268,728 for the twelve months ended. The cost of the transfer between stations net to zero with the exception of $3,442 in freight costs.
(C) Cost of fuel oil received includes a transfer of inventory from Riverbend to Marshall valued at $643,494 in the current month. The cost of the transfer between stations net to zero with the exception of $7,338 in freight costs.
(D) Cost of fuel burned excludes $9,482 associated with emission allowance expense for the month and $79,395 for the twelve months ended.
(E) The current month and twelve months ended data include an annual aerial survey adjustment recorded in Dec 2012.
(F) Cost of biomass burned is reported at book cost prior to the reclassification of fuel expense applicable to NC renewable energy which is $0,000 for the month and -$19,818 for the twelve months ended.
(G) Cost of fuel oil burned includes $3,369 in diesel fuel costs for on-site standby generators for the month and $4,594 for the twelve months ended.
(H) The following CT units were retired October 1, 2012: Buck units 7, 8, & 9; Dan River units 4, 5, & 6; Riverbend units 8, 9, 10, & 11; and Buzzard Roost units 6, 7, 8, 9, 10, 11, 12, 13, 14, & 15.
(H) The following CT units were retired April 1, 2013: Buck units 5 & 6; and Riverbend units 4, 5, 6, & 7.
Detail amounts may not add to totals shown due to rounding.
Fuel cost information on this report does not reflect intercompany sharing of fuel-related merger savings between Duke Energy Carolinas and Progress Energy Carolinas.
Fuel costs based on recoverability unless otherwise noted. Data reflected at 100% ownership.

Exhibit A
Schedule 5

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED CONSUMPTION AND INVENTORY REPORT
May 2013

Description	Allen Steam	Belews Creek Steam	(H) Buck Gas/CC	Cliffside Steam	(H) Dan River Gas/CC	Lee Steam/CT	Lincoln CT	Marshall Steam	Mill Creek CT	(H) Riverbend Steam/CT	Rockingham CT	Current Month	Total 12 ME May 2013
Coal Data:													
Beginning balance	629,343	1,521,829		383,868		130,167		1,754,538		101,380		4,521,125	5,100,193
Tons received during period	11,333	381,550		260,188		-		304,628		-		957,699	11,148,249
Inventory adjustments (A)	836	(285)		1,218		-		(1,031)		-		739	(5,484)
Tons burned during period (B)	15,485	391,304		175,115		-		162,729		-		744,632	11,508,028
Ending balance (C)	626,027	1,511,789		470,160		130,167		1,895,406		101,380		4,734,930	4,734,930
MBTUs per ton burned	21.51	25.11		23.03		-		25.24		-		24.58	24.55
Cost of ending inventory ($/ton) (C)	99.18	96.81		98.48		99.93		101.28		101.85		99.27	99.27
Biomass/Test Fuel Data:													
Beginning balance						-						-	2,222
Tons received during period						-						-	95
Inventory adjustments						-						-	2
Tons burned during period						-						-	2,319
Ending balance						-						-	-
Cost of ending inventory ($/ton)						-						-	-
Fuel Oil Data:													
Beginning balance	83,624	237,168	279,628	129,696	-	545,253	9,815,132	259,537	3,984,186	45,402	2,968,560	18,348,186	18,513,467
Gallons received during period	44,664	96,947		181,367	-	74,650	-	-	-	-	-	397,628	15,761,139
Miscellaneous usage, transfers and adjustments (D)	(406)	(11,132)	(1)	(14,476)	-	(100)	-	191,761	-	(45,402)	-	122,057	(493,013)
Gallons burned during period (E)	15,084	88,388		203,345	-	1,146	3,242	116,875	-	-	-	429,893	15,343,615
Ending balance	112,798	234,595	279,627	93,242	-	618,657	9,811,890	334,423	3,984,186	-	2,968,560	18,437,978	18,437,978
Cost of ending inventory ($/gal)	3.01	3.08	2.99	3.05	-	2.87	1.49	3.14	2.99	-	2.47	2.11	2.11
Gas Data: (F)													
Beginning balance													
MCF received during period (G)			2,182,374		1,625,385	47,045	95,423		73,553	-	164,646	4,188,426	51,892,198
MCF burned during period (G)			2,182,374		1,625,385	47,045	95,423		73,553	-	164,646	4,188,426	51,892,198
Ending balance													
Cost of ending inventory ($/mcf)													
Limestone Data:													
Beginning balance	15,142	36,932		23,701				56,365				132,140	142,267
Tons received during period	-	13,875		13,007				13,876				40,758	504,466
Tons consumed during period (B)	1,190	16,108		12,967				8,971				39,236	513,070
Ending balance	13,952	34,700		23,741				61,270				133,663	133,663
Cost of ending inventory ($/ton)	37.18	33.74		28.43				31.73				32.23	32.23

(A) Coal inventory adjustments include a transfer from Dan River to Belews Creek of 85,903 tons for the twelve months ended. The tons transferred between stations net to zero.
(B) The current month and twelve months ended data include an annual aerial survey adjustment recorded in Dec 2012.
(C) Coal Inventory Ending Balance excludes 60,303 tons and $4,179,534 associated with terminals for the current month.
(D) Fuel Oil inventory adjustments include a transfer from Dan River to Belews Creek of 87,802 gallons for the twelve months ended. The gallons transferred between stations net to zero.
(D) Fuel Oil inventory adjustments include a transfer from Riverbend to Marshall of 210,247 gallons in the current month. The gallons transferred between stations net to zero.
(E) Total gallons of fuel oil burned includes 1813 gallons of diesel fuel oil for on-site standby generators for the month and 5,270 for the twelve months ended. Monthly consumption is reported on a month lag due to timing of data availability. Offsetting activity for the on-site standby generator consumption is reported as miscellaneous usage, transfers and adjustments.
(F) Gas is burned as received; therefore, inventory balances are not maintained.
(G) Twelve months ended Gas MCF received and burned includes 45,015,580 attributable to combined cycle plant activity.
(H) The following CT units were retired October 1, 2012: Buck units 7, 8, & 9; Dan River units 4, 5, & 6; Riverbend units 8, 9, 10, & 11; and Buzzard Roost units 6, 7, 8, 9, 10, 11, 12, 13, 14, & 15.
(H) The following CT units were retired April 1, 2013: Buck units 5 & 6; and Riverbend units 4, 5, 6, & 7.
Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY CAROLINAS
ANALYSIS OF COAL PURCHASES
May 2013

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ALLEN	SPOT	-	-	-
	CONTRACT	11,333	$ 1,035,193.12	$ 91.34
	ADJUSTMENTS	-	-	-
	TOTAL	11,333	1,035,193.12	91.34
BELEWS CREEK	SPOT	(21,597)	(1,317,429.20)	61.00
	CONTRACT	403,147	36,564,477.77	90.70
	ADJUSTMENTS	-	2,188,586.38	-
	TOTAL	381,550	37,435,634.95	98.11
CLIFFSIDE	SPOT	-	-	-
	CONTRACT	260,188	26,566,999.20	102.11
	ADJUSTMENTS	-	264,339.43	-
	TOTAL	260,188	26,831,338.63	103.12
MARSHALL	SPOT	-	-	-
	CONTRACT	304,628	31,345,062.71	102.90
	ADJUSTMENTS	-	1,555,447.21	-
	TOTAL	304,628	32,900,509.92	108.00
ALL PLANTS	SPOT	(21,597)	(1,317,429.20)	61.00
	CONTRACT	979,296	95,511,732.80	97.53
	ADJUSTMENTS	-	4,008,373.02	-
	TOTAL	957,699	$ 98,202,676.62	$ 102.54

Exhibit A
Schedule 8

Duke Energy Carolinas
Analysis of Quality of Coal Received
May 2013

Station	Percent Moisture	Percent Ash	Heat Value	Percent Sulfur
Allen	7.61	14.91	11,281	0.77
Belews Creek	6.70	10.03	12,479	1.21
Cliffside	9.13	9.72	12,064	2.12
Marshall	7.21	8.57	12,714	2.15

Exhibit A
Schedule 9

Duke Energy Carolinas
Analysis of Cost of Oil Purchases
May 2013

Station	**Allen**	**Belews Creek**	**Cliffside**	**Lee**
Vendor	HighTowers	HighTowers	HighTowers	HighTowers
Spot / Contract	Contract	Contract	Contract	Contract
Sulfur Content %	0	0	0	0
Gallons Received	44,664	96,947	181,367	74,650
Total Delivered Cost	$ 129,737.94	$ 286,417.23	$ 550,335.93	$ 207,633.44
Delivered Cost/Gal	$ 2.90	$ 2.95	$ 3.03	$ 2.78
BTU/Gallon	137,900	136,903	137,430	137,743

DUKE ENERGY CAROLINAS
POWER PLANT PERFORMANCE DATA
TWELVE MONTHS SUMMARY
June, 2012 - May, 2013

Plant Name	Generation MWH	Capacity Rating MW	Capacity Factor %	Net Equivalent Availability %
Oconee	21,700,478	2,538	97.61	95.76
McGuire	16,662,667	2,224	85.52	82.89
Catawba	19,270,528	2,258	97.42	94.92

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
June, 2012 through May, 2013

Baseload Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Belews Creek 1	7,486,368	1,110	76.99%	90.60%
Belews Creek 2	6,198,017	1,110	63.74%	88.23%
Cliffside 6	2,072,487	825	69.34%	78.85%
Marshall 3	2,962,100	658	51.39%	70.33%
Marshall 4	3,739,402	660	64.68%	83.77%

Note: This report is limited to capturing data beginning the first full month a unit is in commercial operation.

Cliffside unit 6 net generation (mWh) within the 12 month period was as follows:

June 2012: 1,496 mWh; pre-commercial
July 2012: 77,787 mWh; pre-commercial
August 2012: 212,376 mWh; pre-commercial
September 2012: 139,874 mWh; pre-commercial
October 2012: (1,302) mWh; pre-commercial (auxiliaries only)
November 2012: 170,464 mWh; pre-commercial
December 2012: 168,280 mWh; pre-commercial & commercial combined

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
June, 2012 through May, 2013

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Cliffside 5	1,467,118	555	30.19%	94.22%
Marshall 1	1,204,673	380	36.19%	88.10%
Marshall 2	1,391,160	380	41.79%	88.21%

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
June, 2012 through May, 2013
Other Cycling Coal Units

Unit Name	Net Generation (m Wh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Allen 1	100,352	162	7.07%	91.05%
Allen 2	77,862	162	5.49%	91.03%
Allen 3	592,859	261	25.93%	90.51%
Allen 4	739,433	276	30.58%	94.81%
Allen 5	538,672	266	23.12%	87.41%
Buck 5	198,115	128	21.21%	97.97%
Buck 6	81,237	128	8.70%	98.79%
Lee 1	10,717	100	1.22%	99.93%
Lee 2	20,702	100	2.36%	97.95%
Lee 3	61,448	170	4.13%	99.24%
Riverbend 4	21,749	94	3.17%	99.69%
Riverbend 5	19,720	94	2.88%	99.48%
Riverbend 6	109,255	133	11.26%	98.38%
Riverbend 7	110,206	133	11.36%	98.10%

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
June, 2012 through May, 2013
Combustion Turbines

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Buck CT	-79	21	66.67%
Buzzard Roost CT	-354	100	89.99%
Dan River CT	-28	28	71.96%
Lee CT	52,334	82	97.25%
Lincoln CT	18,634	1,264	94.83%
Mill Creek CT	65,022	592	93.27%
Riverbend CT	-305	37	100.00%
Rockingham CT	465,067	825	51.42%

Notes:

The following units were retired October 1, 2012:

Buck CT units 7, 8, & 9
Buzzard Roost CT units 6, 7, 8, 9, 10, 11, 12, 13, 14, & 15.
Dan River CT units 4, 5, & 6
Riverbend CT units 8, 9, 10, & 11.

The following units were retired April 1, 2013:

Buck CT units 5 & 6
Riverbend CT units 4, 5, 6, & 7.

Duke Energy Carolinas
Power Plant Performance
12 Months Ended May 2013

Name of Plant	Generation (MWH)	Capacity Rating (MW)	Operating Availability (%)
Conventional Hydro Plants:			
Bridgewater	67,625	31.500	98.68
Cedar Creek	127,683	45.000	98.50
Cowans Ford	160,145	325.200	84.14
Dearborn	144,626	42.000	88.09
Fishing Creek	129,417	49.000	97.05
Gaston Shoals	16,953	2.000	45.02
Great Falls	7,772	12.000	89.36
Keowee	48,691	152.000	98.69
Lookout Shoals	86,044	27.900	68.15
Mountain Island	106,807	62.000	95.00
Ninety Nine Island	60,697	6.400	97.38
Oxford	104,095	40.000	66.55
Rhodhiss	65,042	30.000	75.55
Rocky Creek	(215)	-	0.27
Tuxedo	24,744	6.400	93.44
Wateree	187,748	85.000	92.03
Wylie	125,795	72.000	97.39
Nantahala	233,944	50.000	96.37
Queens Creek	3,920	1.440	94.51
Thorpe	74,478	19.700	84.41
Tuckasegee	6,528	2.500	88.88
Tennessee Creek	14,781	9.800	84.81
Bear Creek	29,947	9.450	99.96
Cedar Cliff	21,158	6.400	93.26
Mission	120	0.600	72.99
Franklin	3,368	0.600	79.82
Bryson	504	0.480	99.81
Total Conventional	1,852,416		
Pumped Storage Plants:			
Jocasee	976,876	780.000	92.84
Bad Creek	1,698,010	1,360.000	92.82
Subtotal	2,674,886		
Energy for Pumping:			
Jocasee	(1,182,634)		
Bad Creek	(2,149,171)		
Subtotal	(3,331,805)		
Generation less Energy for Pumping			
Jocassee	(205,758)		
Bad Creek	(451,161)		
Total Pumped Storage	(656,919)		

NOTE:
Capacity MW amounts varied across the range of time indicated.
The amounts shown represent the capacity effective as of the period end date.

Duke Energy Carolinas
Power Plant Performance Data

Twelve Month Summary
June, 2012 through May, 2013
Combined Cycle Units

Unit Name	Net Generation (m Wh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Buck CC 10	4,440,359	620	81.76%	93.06%
Dan River CC 7	1,643,450	620	73.16%	91.31%

Note: This report is limited to capturing data beginning the first full month a station is in commercial operation.

Dan River CC net generation (mWh) within the twelve month period was as follows:

July 2012:	935 mWh; pre-commercial
August 2012:	3,526 mWh; pre-commercial
September 2012:	2,209 mWh; pre-commercial
October 2012:	8,488 mWh; pre-commercial
November 2012:	104,254 mWh; pre-commercial
December 2012:	1,986 mWh; pre-commercial
December 2012:	135,081 mWh; commercial

Smith Rebuttal Exhibit A

Exhibit A
Schedule 11

Duke Energy Carolinas
Month Ending: **May 2013**
Dollars reported in ($)

		Gross Savings			Allocated Savings		DE Carolinas
		DE Carolinas	DE Progress	Combined	DE Carolinas	DE Progress	SC Retail portion
1	Joint Dispatch	$ 898,208	$ 1,237,429	$ 2,135,637	$ 1,404,875	$ 730,762	$ 360,312
2	Coal Blending	4,380,800	-	4,380,800	2,887,675	1,493,125	740,611
3	Coal Procurement	650,001	512,190	1,162,191	767,770	394,421	196,912
4	Coal Transportation	654,275	(207,312)	446,963	308,929	138,034	79,232
5	Reagent Procurement & Transportation	60,980	22,491	83,471	55,239	28,232	14,167
6	Natural Gas Capacity	203,164	-	203,164	134,142	69,022	34,404
7	Natural Gas Trading	35,954	-	35,954	23,737	12,217	6,088
		$ 6,883,382	$ 1,564,798	$ 8,448,180	$ 5,582,368	$ 2,865,812	$ 1,431,727
	Resource ratio %	65.78%	34.22%	100.00%			
	Billed Sales (MWH)				6,096,369		1,563,554
	Sales allocation %						25.65%

Twelve Months Ending: **May 2013**

		Gross Savings			Allocated Savings		DE Carolinas
		DE Carolinas	DE Progress	Combined	DE Carolinas	DE Progress	SC Retail portion
1	Joint Dispatch	$ 16,189,767	$ 16,725,110	$ 32,914,877	$ 20,417,977	$ 12,496,900	$ 5,102,221
2	Coal Blending (a)	33,544,324	-	33,544,324	21,539,628	12,004,696	5,432,459
3	Coal Procurement (a)	3,989,747	5,016,697	9,006,444	5,454,885	3,551,559	1,366,905
4	Coal Transportation (a)	5,253,566	3,357,119	8,610,685	5,296,469	3,314,215	1,326,365
5	Reagent Procurement & Transportation	682,371	648,235	1,330,606	792,218	538,388	199,582
6	Natural Gas Capacity	11,417,283	-	11,417,283	7,088,829	4,328,454	1,755,178
7	Natural Gas Trading	395,494	-	395,494	243,366	152,128	61,143
		$ 71,472,553	$ 25,747,161	$ 97,219,714	$ 60,833,373	$ 36,386,341	$ 15,243,854

Total-to-date: **May 2013**

		Target	Gross Savings			Allocated Savings		DE Carolinas
			DE Carolinas	DE Progress	Combined	DE Carolinas	DE Progress	SC Retail portion
1	Joint Dispatch	$ 318,955,000	$ 16,189,767	$ 16,725,110	$ 32,914,877	$ 20,417,977	$ 12,496,900	$ 5,102,221
2	Coal Blending (b)	259,800,000	40,491,719	-	40,491,719	28,487,023	12,004,696	7,220,737
3	Coal Procurement (b)	45,950,000	4,620,824	5,199,590	9,820,414	6,085,961	3,734,453	1,528,598
4	Coal Transportation (b)	30,395,000	5,243,223	3,576,687	8,819,910	5,286,126	3,533,784	1,323,636
5	Reagent Procurement & Transportation	12,800,000	769,635	864,558	1,634,193	879,482	754,711	222,147
6	Natural Gas Capacity	16,900,000	11,417,283	-	11,417,283	7,088,829	4,328,454	1,755,178
7	Natural Gas Trading	2,000,000	395,494	-	395,494	243,366	152,128	61,143
		$ 686,800,000	$ 79,127,945	$ 26,365,945	$ 105,493,890	$ 68,488,765	$ 37,005,125	$ 17,213,660

(a) Includes June 2012 savings associated with fuel-related savings guarantee, retained by the originating company.
(b) Includes January – June 2012 savings associated with fuel-related savings guarantee, retained by the originating company.
Note: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY CAROLINAS
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN

PERIOD: May, 2013

PLANT	UNIT	DATE OF OUTAGE	DURATION OF OUTAGE	SCHEDULED / UNSCHEDULED	CAUSE OF OUTAGE	REASON OUTAGE OCCURRED	REMEDIAL ACTION TAKEN
Oconee	1	None					
	2	None					
	3	None					
McGuire	1	None					
	2	None					
Catawba	1	None					
	2	None					

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

May 2013

Belews Creek Station

No Outages During The Month.

Cliffside Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
CS06	4/30/2013 3:03:00 AM To 5/3/2013 10:00:00 AM	Unsch	0790	Pipe Hangers (General)	FOUND DAMAGE TO ECONOMIZER INLET LINE HANGER ON 7TH FLOOR. EVALUATING DAMAGE	

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
CS06	5/3/2013 10:00:00 AM To 5/3/2013 8:35:00 PM	Sch	0680	Feedwater Valves (not Feedwater Regulating Valve)	FEEDWATER VALVE REPAIR	

Marshall Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
MS03	3/1/2013 6:51:00 PM To 6/1/2013	Sch	4400	Major Turbine Overhaul (720 Hours Or Longer)	Turbine/Boiler Planned Outage.	

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
MS04	3/29/2013 6:04:00 PM To 5/16/2013 8:44:00 PM	Sch	4212	Lp Turbine Buckets Or Blades	Low Pressure Turbine Blade Inspection/Replacement.	

Buck Combined Cycle

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
BK 10	4/26/2013 12:01:00 AM To 5/6/2013 5:50:00 AM	Sch	5083	Gas Turbine - High Pressure Nozzles/vanes	GT11 & GT12 - Boroscope inspectIon of nozzles and vanes.	

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

May 2013

Dan River Combined Cycle

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
DR 07	5/5/2013 9:07:00 PM To 5/10/2013 5:00:00 PM	Unsch	4264	Turbine Combined Intercept Valves	PLANT - ST 07 #1 IV failed daily valve test unit removed from operation per GE rec.	

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
DR 07	5/27/2013 12:00:00 PM To 5/27/2013 8:33:00 PM	Unsch	3330	Condensate Valves	PLANT - Condensate system relief valve lifting prematurely.	

Duke Energy Carolinas
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN

May 2013
Oconee Nuclear Station

	Unit 1		Unit 2		Unit 3	
(A) MDC (MW)	846		846		846	
(B) Period Hours	744		744		744	
(C1) Net Gen (MWH) and Capacity Factor	641971	101.99	644704	102.43	652100	103.60
(D1) Net MWH Not Gen Due To Full Schedule Outages	0	0.00	0	0.00	0	0.00
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	0	0.00	0	0.00	92	0.01
(E1) Net MWH Not Gen Due To Full Forced Outages	0	0.00	0	0.00	0	0.00
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-12547	-1.99	-15280	-2.43	-22768	-3.61
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00	0	0.00
(H) Net MWH Possible In Period	629424	100.00%	629424	100.00%	629424	100.00%
(I) Equivalent Availability		100.00		100.00		99.99
(J) Output Factor		101.99		102.43		103.60
(K) Heat Rate		10,142		10,099		9,991

*** Estimate**
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN

May 2013
McGuire Nuclear Station

	Unit 1		Unit 2	
(A) MDC (MW)	1129		1129	
(B) Period Hours	744		744	
(C1) Net Gen (MWH) and Capacity Factor	866187	103.12	861315	102.54
(D1) Net MWH Not Gen Due To Full Schedule Outages	0	0.00	0	0.00
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	0	0.00	3835	0.46
(E1) Net MWH Not Gen Due To Full Forced Outages	0	0.00	0	0.00
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-26211	-3.12	-25174	-3.00
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00
(H) Net MWH Possible In Period	839976	100.00%	839976	100.00%
(I) Equivalent Availability		100.00		99.54
(J) Output Factor		103.12		102.54
(K) Heat Rate		9,989		9,999

*** Estimate**
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN

May 2013
Catawba Nuclear Station

	Unit 1		Unit 2	
(A) MDC (MW)	1129		1129	
(B) Period Hours	744		744	
(C1) Net Gen (MWH) and Capacity Factor	860126	102.40	825540	98.28
(D1) Net MWH Not Gen Due To Full Schedule Outages	0	0.00	0	0.00
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	187	0.02	35561	4.23
(E1) Net MWH Not Gen Due To Full Forced Outages	0	0.00	0	0.00
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-20337	-2.42	-21125	-2.51
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00
(H) Net MWH Possible In Period	839976	100.00%	839976	100.00%
(I) Equivalent Availability		99.98		95.77
(J) Output Factor		102.40		98.28
(K) Heat Rate		10,044		10,057

* Estimate
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

May 2013

Belews Creek Station

	Belews Creek 1	Belews Creek 2
(A) MDC (mw)	1,110	1,110
(B) Period Hrs	744	744
(C1) Net Generation (mWh)	380,497	689,696
(C1) Capacity Factor	46.07	83.51
(D1) Net mWh Not Generated due to Full Scheduled Outages	0	0
(D1) Scheduled Outages: percent of Period Hrs	0.00	0.00
(D2) Net mWh Not Generated due to Partial Scheduled Outages	1,355	0
(D2) Scheduled Derates: percent of Period Hrs	0.16	0.00
(E1) Net mWh Not Generated due to Full Forced Outages	0	0
(E1) Forced Outages: percent of Period Hrs	0.00	0.00
(E2) Net mWh Not Generated due to Partial Forced Outages	1,432	0
(E2) Forced Derates: percent of Period Hrs	0.17	0.00
(F) Net mWh Not Generated due to Economic Dispatch	442,557	136,144
(F) Economic Dispatch: percent of Period Hrs	53.59	16.49
(G) Net mWh Possible in Period	825,840	825,840
(H) Equivalent Availability	99.66	100.00
(I) Output Factor (%)	85.95	83.51
(J) Heat Rate (BTU/NkWh)	9,394	9,083

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

May 2013

Buck Combined Cycle

	Buck CC 10
(A) MDC (mw)	620
(B) Period Hrs	744
(C1) Net Generation (mWh)	306,042
(C1) Capacity Factor	66.35
(D1) Net mWh Not Generated due to Full Scheduled Outages	78,017
(D1) Scheduled Outages: percent of Period Hrs	16.91
(D2) Net mWh Not Generated due to Partial Scheduled Outages	19,003
(D2) Scheduled Derates: percent of Period Hrs	0.00
(E1) Net mWh Not Generated due to Full Forced Outages	0
(E1) Forced Outages: percent of Period Hrs	0.00
(E2) Net mWh Not Generated due to Partial Forced Outages	0
(E2) Forced Derates: percent of Period Hrs	0.00
(F) Net mWh Not Generated due to Economic Dispatch	58,218
(F) Economic Dispatch: percent of Period Hrs	12.62
(G) Net mWh Possible in Period	461,280
(H) Equivalent Availability	78.97
(I) Output Factor (%)	79.85
(J) Heat Rate (BTU/NkWh)	6,833

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

May 2013
Cliffside Station

	Cliffside 6
(A) MDC (mw)	825
(B) Period Hrs	744
(C1) Net Generation (mWh)	425,751
(C1) Capacity Factor	69.36
(D1) Net mWh Not Generated due to Full Scheduled Outages	8,731
(D1) Scheduled Outages: percent of Period Hrs	1.42
(D2) Net mWh Not Generated due to Partial Scheduled Outages	0
(D2) Scheduled Derates: percent of Period Hrs	0.00
(E1) Net mWh Not Generated due to Full Forced Outages	47,850
(E1) Forced Outages: percent of Period Hrs	7.80
(E2) Net mWh Not Generated due to Partial Forced Outages	0
(E2) Forced Derates: percent of Period Hrs	0.00
(F) Net mWh Not Generated due to Economic Dispatch	131,468
(F) Economic Dispatch: percent of Period Hrs	21.42
(G) Net mWh Possible in Period	613,800
(H) Equivalent Availability	90.78
(I) Output Factor (%)	84.01
(J) Heat Rate (BTU/NkWh)	9,052

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

May 2013

Dan River Combined Cycle

	Dan River CC 7
(A) MDC (mw)	620
(B) Period Hrs	744
(C1) Net Generation (mWh)	232,467
(C1) Capacity Factor	50.40
(D1) Net mWh Not Generated due to Full Scheduled Outages	0
(D1) Scheduled Outages: percent of Period Hrs	0.00
(D2) Net mWh Not Generated due to Partial Scheduled Outages	13,425
(D2) Scheduled Derates: percent of Period Hrs	2.91
(E1) Net mWh Not Generated due to Full Forced Outages	77,149
(E1) Forced Outages: percent of Period Hrs	16.72
(E2) Net mWh Not Generated due to Partial Forced Outages	972
(E2) Forced Derates: percent of Period Hrs	0.21
(F) Net mWh Not Generated due to Economic Dispatch	137,267
(F) Economic Dispatch: percent of Period Hrs	29.76
(G) Net mWh Possible in Period	461,280
(H) Equivalent Availability	80.15
(I) Output Factor (%)	76.48
(J) Heat Rate (BTU/NkWh)	7,061

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

May 2013

Marshall Station

	Marshall 3	Marshall 4
(A) MDC (mw)	658	660
(B) Period Hrs	744	744
(C1) Net Generation (mWh)	-1,127	168,314
(C1) Capacity Factor	0.00	34.28
(D1) Net mWh Not Generated due to Full Scheduled Outages	489,552	251,284
(D1) Scheduled Outages: percent of Period Hrs	100.00	51.17
(D2) Net mWh Not Generated due to Partial Scheduled Outages	0	0
(D2) Scheduled Derates: percent of Period Hrs	0.00	0.00
(E1) Net mWh Not Generated due to Full Forced Outages	0	0
(E1) Forced Outages: percent of Period Hrs	0.00	0.00
(E2) Net mWh Not Generated due to Partial Forced Outages	0	1,011
(E2) Forced Derates: percent of Period Hrs	0.00	0.21
(F) Net mWh Not Generated due to Economic Dispatch	1,127	70,431
(F) Economic Dispatch: percent of Period Hrs	0.23	14.34
(G) Net mWh Possible in Period	489,552	491,040
(H) Equivalent Availability	0.00	48.62
(I) Output Factor (%)	0.00	70.20
(J) Heat Rate (BTU/NkWh)	0	9,626

Duke Energy Carolinas
Intermediate Power Plant
Performance Review Plan

May 2013
Cliffside Steam Station

		Cliffside 5
(A)	**MDC (mWh)**	556
(B)	**Period Hrs**	744
(C1)	**Net Generation (mWh)**	14,993
(D)	**Net mWh Possible in Period**	413,664
(E)	**Equivalent Availability**	94.82
(F)	**Output Factor (%)**	55.56
(G)	**Capacity Factor**	3.62

Duke Energy Carolinas
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN

June 2012 - May 2013
Oconee Nuclear Station

	Unit 1		Unit 2		Unit 3	
(A) MDC (MW)	846		846		846	
(B) Period Hours	8760		8760		8760	
(C1) Net Gen (MWH) and Capacity Factor	6686327	90.22	7543922	101.79	7470229	100.80
(D1) Net MWH Not Gen Due To Full Schedule Outages	589282	7.95	0	0.00	134624	1.82
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	18223	0.25	1588	0.02	4047	0.05
(E1) Net MWH Not Gen Due To Full Forced Outages	155672	2.10	0	0.00	0	0.00
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-38544	-0.52	-134550	-1.81	-197940	-2.67
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00	0	0.00
(H) Net MWH Possible In Period	7410960	100.00%	7410960	100.00%	7410960	100.00%
(I) Equivalent Availability		89.25		99.98		98.04
(J) Output Factor		100.30		101.79		102.66
(K) Heat Rate		10,244		10,160		10,003

*** Estimate**
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN

June 2012 - May 2013
McGuire Nuclear Station

	Unit 1		Unit 2	
(A) MDC (MW)	1129		1129	
(B) Period Hours	8760		8760	
(C1) Net Gen (MWH) and Capacity Factor	8817120	90.51	7845547	80.53
(D1) Net MWH Not Gen Due To Full Schedule Outages	975456	10.01	1003200	10.30
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	46476	0.48	71188	0.73
(E1) Net MWH Not Gen Due To Full Forced Outages	123818	1.27	1042690	10.70
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-221803	-2.27	-221558	-2.26
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00
(H) Net MWH Possible In Period	9741067	100.00%	9741067	100.00%
(I) Equivalent Availability		87.79		77.99
(J) Output Factor		101.83		102.24
(K) Heat Rate		10,135		10,095

* Estimate
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN

June 2012 - May 2013

Catawba Nuclear Station

	Unit 1		Unit 2	
(A) MDC (MW)	1129		1129	
(B) Period Hours	8760		8760	
(C1) Net Gen (MWH) and Capacity Factor	9131298	92.33	10139230	102.52
(D1) Net MWH Not Gen Due To Full Schedule Outages	708673	7.17	0	0.00
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	27605	0.28	36913	0.37
(E1) Net MWH Not Gen Due To Full Forced Outages	220855	2.23	0	0.00
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-198391	-2.01	-286103	-2.89
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00
(H) Net MWH Possible In Period	9890040	100.00%	9890040	100.00%
(I) Equivalent Availability		90.22		99.63
(J) Output Factor		101.91		102.52
(K) Heat Rate		10,054		9,997

*** Estimate**
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

June, 2012 through May, 2013

Belews Creek Station

	Belews Creek 1	Belews Creek 2
(A) MDC (mw)	1,110	1,110
(B) Period Hrs	8,760	8,760
(C1) Net Generation (mWh)	7,486,368	6,198,017
(C1) Capacity Factor	76.99%	63.74%
(D1) Net mWh Not Generated due to Full Scheduled Outages	528,915	953,083
(D1) Scheduled Outages: percent of Period Hrs	5.44%	9.80%
(D2) Net mWh Not Generated due to Partial Scheduled Outages	86,191	45,535
(D2) Scheduled Derates: percent of Period Hrs	0.77%	0.46%
(E1) Net mWh Not Generated due to Full Forced Outages	277,574	36,741
(E1) Forced Outages: percent of Period Hrs	2.85%	0.38%
(E2) Net mWh Not Generated due to Partial Forced Outages	20,993	109,209
(E2) Forced Derates: percent of Period Hrs	0.22%	1.12%
(F) Net mWh Not Generated due to Economic Dispatch	1,323,559	2,381,015
(F) Economic Dispatch: percent of Period Hrs	13.61%	24.49%
(G) Net mWh Possible in Period	9,723,600	9,723,600
(H) Equivalent Availability	90.60	88.23
(I) Output Factor (%)	88.49%	82.81%
(J) Heat Rate (BTU/NkWh)	9,097	9,269

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

June, 2012 through May, 2013

Buck Combined Cycle

	Buck CC 10
(A) MDC (mw)	620
(B) Period Hrs	8,760
(C1) Net Generation (mWh)	4,440,359
(C1) Capacity Factor	81.76%
(D1) Net mWh Not Generated due to Full Scheduled Outages	338,127
(D1) Scheduled Outages: percent of Period Hrs	6.23%
(D2) Net mWh Not Generated due to Partial Scheduled Outages	43,312
(D2) Scheduled Derates: percent of Period Hrs	0.00%
(E1) Net mWh Not Generated due to Full Forced Outages	38,636
(E1) Forced Outages: percent of Period Hrs	0.71%
(E2) Net mWh Not Generated due to Partial Forced Outages	50,221
(E2) Forced Derates: percent of Period Hrs	0.92%
(F) Net mWh Not Generated due to Economic Dispatch	520,544
(F) Economic Dispatch: percent of Period Hrs	9.58%
(G) Net mWh Possible in Period	5,431,200
(H) Equivalent Availability	91.34
(I) Output Factor (%)	88.14%
(J) Heat Rate (BTU/NkWh)	7,060

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

June, 2012 through May, 2013

Cliffside Station

	Cliffside 6
(A) MDC (mw)	825
(B) Period Hrs	3,623
(C1) Net Generation (mWh)	2,072,487
(C1) Capacity Factor	69.34%
(D1) Net mWh Not Generated due to Full Scheduled Outages	172,879
(D1) Scheduled Outages: percent of Period Hrs	5.78%
(D2) Net mWh Not Generated due to Partial Scheduled Outages	0
(D2) Scheduled Derates: percent of Period Hrs	0.00%
(E1) Net mWh Not Generated due to Full Forced Outages	326,466
(E1) Forced Outages: percent of Period Hrs	10.92%
(E2) Net mWh Not Generated due to Partial Forced Outages	132,679
(E2) Forced Derates: percent of Period Hrs	4.44%
(F) Net mWh Not Generated due to Economic Dispatch	284,464
(F) Economic Dispatch: percent of Period Hrs	9.52%
(G) Net mWh Possible in Period	2,988,975
(H) Equivalent Availability	78.85
(I) Output Factor (%)	86.45%
(J) Heat Rate (BTU/NkWh)	8,836

Note: This report is limited to capturing data beginning the first full month a unit is in commercial operation.

Cliffside unit 6 net generation (mWh) within
the 12 month period was as follows:

June 2012: 1,496 mWh; pre-commercial
July 2012: 77,787 mWh; pre-commercial
Aug 2012: 212,376 mWh; pre-commercial
Sept 2012: 139,874 mWh; pre-commercial
Oct 2012: (1,302) mWh; pre-commercial (auxiliaries only)
Nov 2012: 170,464 mWh; pre-commercial
Dec 2012: 168,280 mWh; pre-

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

June, 2012 through May, 2013

Dan River Combined Cycle

	Dan River CC 7
(A) MDC (mw)	620
(B) Period Hrs	3,623
(C1) Net Generation (mWh)	1,643,450
(C1) Capacity Factor	73.16%
(D1) Net mWh Not Generated due to Full Scheduled Outages	111,032
(D1) Scheduled Outages: percent of Period Hrs	4.94%
(D2) Net mWh Not Generated due to Partial Scheduled Outages	13,624
(D2) Scheduled Derates: percent of Period Hrs	0.61%
(E1) Net mWh Not Generated due to Full Forced Outages	84,155
(E1) Forced Outages: percent of Period Hrs	3.75%
(E2) Net mWh Not Generated due to Partial Forced Outages	11,041
(E2) Forced Derates: percent of Period Hrs	0.49%
(F) Net mWh Not Generated due to Economic Dispatch	382,959
(F) Economic Dispatch: percent of Period Hrs	17.05%
(G) Net mWh Possible in Period	2,246,260
(H) Equivalent Availability	90.21
(I) Output Factor (%)	85.27%
(J) Heat Rate (BTU/NkWh)	7,080

Note: This report is limited to capturing data beginning the first full month a station is in commercial operation.

Dan River CC net generation (mWh) within the twelve month period was as follows:

July 2012:	935 mWh; pre-commercial
Aug 2012:	3,526 mWh; pre-commercial
Sept 2012:	2,209 mWh; pre-commercial
Oct 2012:	8,488 mWh; pre-commercial
Nov 2012:	104,254 mWh; pre-commercial
Dec 2012:	1,986 mWh; pre-commercial
Dec 2012:	135,081 mWh; commercial

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

June, 2012 through May, 2013

Marshall Station

	Marshall 3	Marshall 4
(A) MDC (mw)	658	660
(B) Period Hrs	8,760	8,760
(C1) Net Generation (mWh)	2,962,100	3,739,402
(C1) Capacity Factor	51.39%	64.68%
(D1) Net mWh Not Generated due to Full Scheduled Outages	1,647,522	762,080
(D1) Scheduled Outages: percent of Period Hrs	28.58%	13.18%
(D2) Net mWh Not Generated due to Partial Scheduled Outages	6,043	14,072
(D2) Scheduled Derates: percent of Period Hrs	0.10%	0.24%
(E1) Net mWh Not Generated due to Full Forced Outages	0	133,980
(E1) Forced Outages: percent of Period Hrs	0.00%	2.32%
(E2) Net mWh Not Generated due to Partial Forced Outages	56,497	28,115
(E2) Forced Derates: percent of Period Hrs	0.98%	0.49%
(F) Net mWh Not Generated due to Economic Dispatch	1,091,918	1,103,951
(F) Economic Dispatch: percent of Period Hrs	18.94%	19.09%
(G) Net mWh Possible in Period	5,764,080	5,781,600
(H) Equivalent Availability	70.33	83.77
(I) Output Factor (%)	75.20%	76.54%
(J) Heat Rate (BTU/NkWh)	9,581	9,431

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Intermediate Power Plant
Performance Review Plan

June 2012 through May 2013

Cliffside Station

	Cliffside 5
(A) MDC (mWh)	555
(B) Period Hrs	8,760
(C1) Net Generation (mWh)	1,467,118
(D) Net mWh Possible in Period	4,858,848
(E) Equivalent Availability	94.22
(F) Output Factor (%)	74.17%
(G) Capacity Factor	30.19%

DUKE ENERGY CAROLINAS
Outages for 100MW or Larger Units
May 2013

Full Outage Hours

	Unit	MW	Scheduled	Unscheduled	Total
Oconee	1	846	0.00	0.00	0.00
	2	846	0.00	0.00	0.00
	3	846	0.00	0.00	0.00
McGuire	1	1129	0.00	0.00	0.00
	2	1129	0.00	0.00	0.00
Catawba	1	1129	0.00	0.00	0.00
	2	1129	0.00	0.00	0.00

Duke Energy Carolinas

Outages for 100 mW or Larger Units

May 2013

Unit Name	Capacity Rating (mW)	Full Outage Hours Scheduled	Full Outage Hours Unscheduled	Total Outage Hours
Allen 1	162	0.00	0.00	0.00
Allen 2	162	0.00	0.00	0.00
Allen 3	261	24.00	0.00	24.00
Allen 4	276	0.00	0.00	0.00
Allen 5	266	0.00	0.00	0.00
Belews Creek 1	1,110	0.00	0.00	0.00
Belews Creek 2	1,110	0.00	0.00	0.00
Buck CC 10	620	125.83	0.00	125.83
Cliffside 5	556	34.03	4.42	38.45
Cliffside 6	825	10.58	58.00	68.58
Dan River CC 7	620	0.00	124.43	124.43
Lee 1	100	0.00	0.00	0.00
Lee 2	100	0.00	0.00	0.00
Lee 3	170	0.00	0.00	0.00
Marshall 1	380	53.40	3.93	57.33
Marshall 2	380	145.65	0.00	145.65
Marshall 3	658	744.00	0.00	744.00
Marshall 4	660	380.73	0.00	380.73
Rockingham CT1	165	20.40	0.00	20.40
Rockingham CT2	165	0.00	712.92	712.92
Rockingham CT3	165	0.00	0.00	0.00
Rockingham CT4	165	240.77	236.85	477.62
Rockingham CT5	165	0.75	0.00	0.75